

Alberta PETROLEUM MARKETING COMMISSION

1983 ANNUAL REPORT

Alberta PETROLEUM MARKETING COMMISSION

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May 31, 1984

The Honourable E.P. Lougheed, Premier
and
The Honourable John Zaccirny, Minister
Government of the Province of Alberta
Legislature Building
Edmonton, Alberta
T5K 2B7

Gentlemen,

In accordance with the provisions of the Petroleum Marketing Act and the Natural Gas Pricing Agreement Act, the Commission has prepared a general report summarizing its transactions and affairs for the fiscal year ended December 31, 1983. I have the pleasure to submit the 1983 Annual Report that you may lay a copy before the Legislative Assembly.

Respectfully,



D.W. Minion
Chairman





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"Dingman 1 & 2" Roland Gissing, 1895-1967. Spudded January 13, 1914 beside the Sheep River near Turner Valley, Alberta, the Dingman well roared to life with a flow of natural gas saturated with a light oil the color of straw. (Philip Smith, *The Treasure Seekers*, (Toronto: MacMillan), 1978, p. 18.)
Courtesy Glenbow-Alberta Institute.

FOREWORD

In many respects, 1983 was another year of the unexpected. For the first time, OPEC reduced the marker price for crude oil and imposed production quotas. Both the U.K. and Mexico aligned their policies with OPEC to stabilize the market. Even a recovering world economy and cold weather in the United States were unable to stimulate demand or do more than nudge up spot prices at year end.

In the broader scene, surpluses of supply became evident for all major energy forms. Additional gas supplies entered Europe through the Trans-Mediterranean pipeline from Africa and the Yamal pipeline from the U.S.S.R. Plentiful electrical generating capacity was available in all O.E.C.D. countries. Coal increased its market share in the U.S.A., where productive capacity continued well in excess of demand.

The perception of the 70's of a world short of energy in the 80's has not materialized. Nor is it likely to during the balance of the decade, given the high levels of surplus productive capacity which are now evident.

Perhaps the single most important lesson learned from the last ten years' events is that the free market system, even with its imperfections, does work and that increasing price is an effective way to moderate demand and stimulate supply.

Within the natural gas industry, 1983 was a year in which there was a clear redistribution of risk,

away from distributors towards pipeline companies and producers. After all, why should consumers pay a premium for gas supply when it is possible to switch to an alternate fuel where premiums are not required? The development of spot sales in the U.S.A. capturing some six percent of the natural gas market was a clear indication that the market system is working.

In Canada, the pressures or forces that produced the confrontations between the Alberta government and the federal government abated. The spectre of endlessly rising oil prices vanished and with it the expectation of ever larger amounts of economic rent to cushion government deficits. The need for a healthy, viable petroleum industry to assure oil self-sufficiency and to underpin economic recovery was finally recognized and necessary changes were made to royalty and tax regimes. The stage appears set for a return to a simpler, less regulated system of selling oil and natural gas with prices being determined through negotiations between buyers and sellers, where access to market is not unreasonably constrained by government policies or regulatory actions.

For the first time since the Arab embargo of 1973, Canadians can look forward to a period of stable energy prices, abundant energy supplies and decreasing government control and intervention.

PETROLEUM

FUNCTIONS AND RESPONSIBILITIES

The Petroleum Marketing Act created the Commission as agent to sell the Crown's royalty share and lessee's share of petroleum and pentanes plus from Crown leases. The Commission administers the Act through procedures that include the following:

- issuance of price bulletins in which the Commission prescribes selling prices for petroleum and pentanes plus;
- designation of operators to make deliveries of petroleum and pentanes plus from Crown leases to the Commission;
- movement of petroleum and pentanes plus from point of receipt to point of sale to buyers;
- sale of petroleum and pentanes plus by the Commission to buyers;
- remittance of proceeds of sale of the lessee's share to designated operators for distribution to owners;
- remittance of proceeds of sale of the Crown's royalty share to the Provincial Treasurer.

The Memorandum of Agreement of September 1, 1981 between the Government of Canada and the Government of Alberta relating to Energy Pricing and Taxation (the 'Canada-Alberta agreement') established higher prices (NORP) for 'new' oil, effective January 1, 1982 and 'new' pentanes plus and bitumen effective April 1, 1982. Oil and pentanes plus eligible for 'new' status is that discovered after December 31, 1980. The National Energy Program Update of May, 1982 established, as of July 1, 1982, a special old oil

price (SOOP) for oil discovered between April 1, 1974 and December 31, 1980. Pentanes plus discovered between January 1, 1974 and December 31, 1980 also became eligible for SOOP. As a result of a June 30, 1983 amendment to the Canada-Alberta agreement, oil and pentanes plus eligible for SOOP prices received NORP prices effective July 1, 1983.

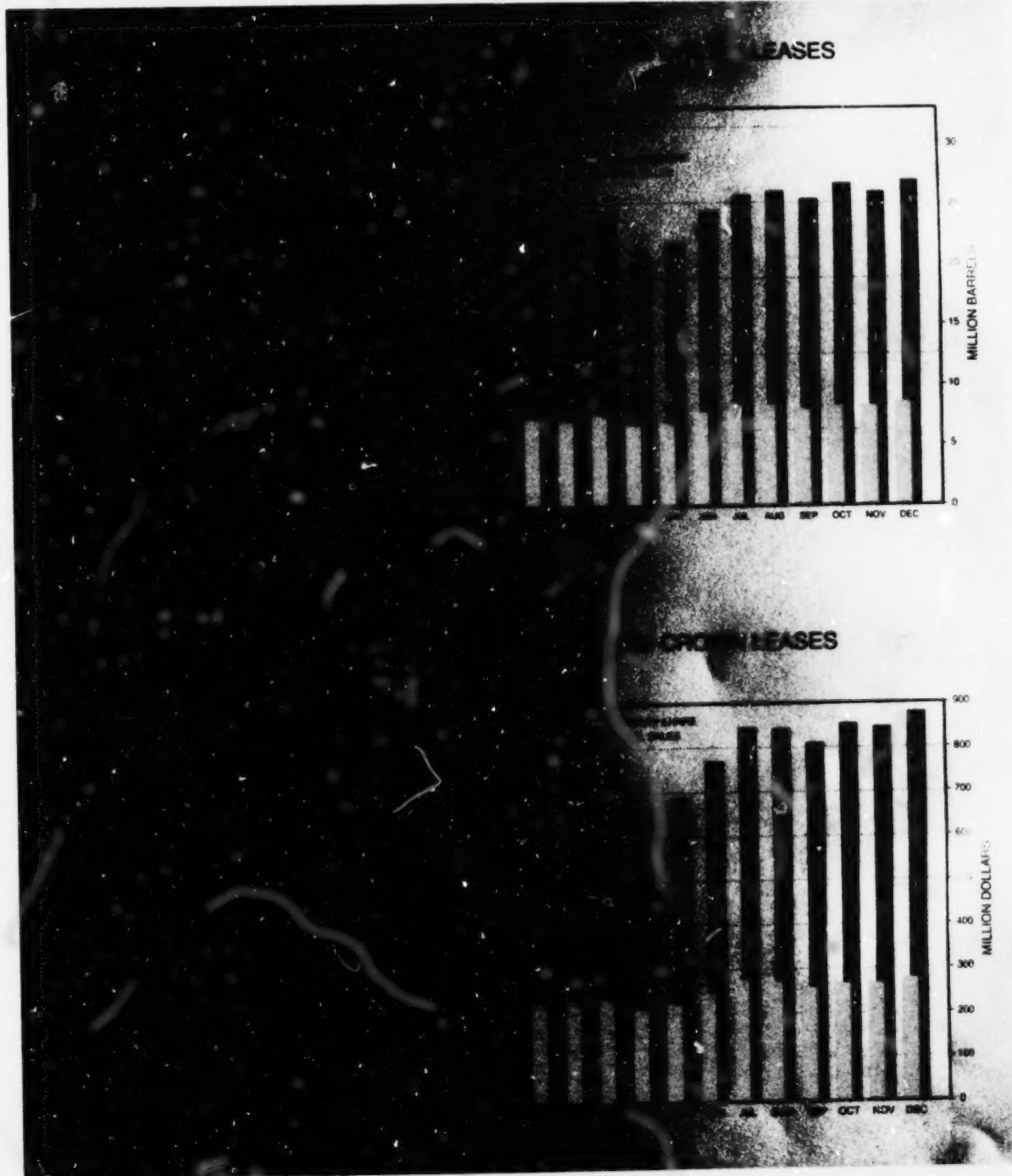
The Commission sells petroleum and pentanes plus to buyers at conventional old oil prices and distributes NORP and SOOP supplementary payments to producers for the difference between the conventional old oil prices and the NORP/SOOP prices.

In addition to marketing Crown lease petroleum, pentanes plus and bitumen, the Commission also purchases and markets these substances produced from certain lands other than Alberta Crown lands, under private contracts with producers.

SALES

During the year the Commission sold 53 million cubic metres of petroleum, pentanes plus and bitumen from Crown and freehold lands. These sales, together with NORP and SOOP supplements totalling \$780 million, realized total revenues of \$10.8 billion. Of that amount, 47 million cubic metres from Crown lands were sold for \$9.5 billion. The Crown royalty share totalled 15 million cubic metres, representing revenue of \$3 billion.

Monthly average volumes of sales from Crown leases are shown in Figure 1, with the value of those sales shown in Figure 2.



PRICING

The price bulletins issued by the Commission prescribe the prices for petroleum, pentanes plus and bitumen marketed by the Commission, incorporating variations in quality based on density and sulphur content.

Posted field prices during the year for petroleum with a density of 825 to 844 kilograms per cubic metre and a sulphur content of 2.5 to 4.9 grams per kilogram are shown in Table 1.

TABLE 1
FIELD PRICE*
(\$ cubic metre)

1983	Old Oil	NORP Oil	SOOP Oil
January	187.75	276.15	195.50
February—March	187.75	273.30	193.30
April	187.75	269.80	191.35
May	187.75	266.20	188.70
June	187.75	262.10	187.75
July	187.75	250.60	
August	187.75	240.15	
Sept. — October	187.75	231.90	
November	187.75	239.80	
December	187.75	242.90	

* Prices for petroleum with a quality of — density of 825 to 844 kilograms per cubic metre and a sulphur content of 2.5 to 4.9 grams per kilogram.

Old oil field prices are maintained at an average field price as specified in the 'Canada-Alberta agreement'. The January 1, 1983 price was effective throughout the year.

Table 2 shows the average old oil field prices for conventional crude oil for the period from January 1, 1978 to January 1, 1983.

TABLE 2
AVERAGE OLD OIL FIELD PRICE

Effective Date	\$ Barrel	\$ Cubic Metre
Jan. 1, 1978	11.75	
Jul. 1, 1978	12.75	
Jul. 1, 1979	13.75	86.53
Jan. 1, 1980	14.75	92.83
Aug. 1, 1980	16.75	105.40
Jan. 1, 1981	17.75	111.70
Jul. 1, 1981	18.75	117.99
Oct. 1, 1981	21.25	133.72
Jan. 1, 1982	23.50	147.88
Jul. 1, 1982	25.75	162.04
Jan. 1, 1983	29.75	187.21

NATURAL GAS

FUNCTIONS AND RESPONSIBILITIES

The Canada-Alberta agreement on natural gas pricing is implemented by the Natural Gas Pricing Agreement Act governing field prices of natural gas production in Alberta.

The functions and responsibilities of the Commission with respect to the Act are as follows:

- determination of Alberta costs of service for original buyers;
- purchase of gas and its subsequent resale;
- administration of the Natural Gas Pricing Agreement Act Fund (the 'Fund') comprised of revenues derived from gas exports to the United States;
- determination of a price adjustment to be paid each month to producers with respect to eligible gas;
- reimbursement or payment of a price adjustment from revenues in the Fund;
- determination and payment of market development incentive payments to the federal government from the Fund.

PRICING

Under the Act the monthly regulated field price for natural gas purchased by original buyers that remove gas from Alberta is: Alberta Border Price less Alberta Cost of Service plus Price Adjustment

Natural gas purchased for consumption within Alberta is required to be priced as described above or at the contract field price specified in a natural gas sales contract plus a price adjustment, whichever is the lesser. Figure 3 shows average regulated field prices during the past five years.

The Canada-Alberta agreement on natural gas pricing covering the period November 1, 1981, to January 31, 1987 established an initial Alberta border price of \$1.701 62 per gigajoule and provided for subsequent increases of approximately

\$0.23 per gigajoule every six months during the term of the agreement. On June 30, 1983 an amendment was made which provides that, during the eighteen month period commencing August 1, 1983, natural gas prices at the Alberta border would be determined on the basis of 65 per cent of the price of domestic crude oil at Toronto, less transportation costs from the Alberta border to the Eastern Zone and federal charges. The calculation of the border price is conditional upon the federal government reducing the Natural Gas and Gas Liquids Tax as needed to accommodate increases in the Alberta border price as specified in the September 1981 agreement, until the tax reaches zero. Further, increases in transmission tolls to eastern Canada greater than five percent of tolls in effect at June 30, 1983 are to be subsidized by the federal government with funds expected to be taken from proceeds of the Canadian Ownership Special Charge.

Table 3 shows a history of the Toronto city gate price, transportation cost from Alberta to Toronto and Alberta border price.

TABLE 3
HISTORY OF NATURAL GAS PRICES AND
TRANSPORTATION COSTS
(\$/gigajoule)

Date	Toronto City Gate Price ⁽¹⁾	Alberta-Toronto Transportation Cost	Imputed Alberta Border Price
Jan. 1, 1979	1.864 06	.550 11	1.313 95
Aug. 1, 1979	2.003 86	.590 89	1.412 97
Feb. 1, 1980	2.143 67	.602 61	1.541 06
Sept. 1, 1980	2.423 28	.629 20	1.794 08
Nov. 1, 1980	2.423 28	.647 63	1.775 65 ⁽²⁾
Sept. 1, 1981	2.423 28	.721 66	1.701 62 ⁽²⁾⁽³⁾
Feb. 1, 1982	2.683 90	.749 27	1.934 63
Aug. 1, 1982	2.931 83	.764 19	2.167 64
Sept. 1, 1982	3.047 59	.879 95	2.167 64
Feb. 1, 1983	3.284 10	.883 45	2.400 65
Aug. 1, 1983	3.570 67	.937 01	2.633 66

⁽¹⁾ Does not include Federal excise taxes.

⁽²⁾ Established by the Government of Canada pursuant to the Petroleum Administration Act.

⁽³⁾ Alberta border price confirmed by Canada-Alberta agreement effective November 1, 1981.

PRICE ADJUSTMENT

Substantially all natural gas acquired by original buyers in Alberta is purchased by the Commission. Gas destined for the Canadian market is sold back to the original buyer at the purchase price. Gas destined for export to the United States is resold to the original buyer at the export price less transmission costs. As a result of these buy/sell transactions for export gas, proceeds are obtained for the Fund out of which price adjustment and market development incentive payments are made.

The quantities and destination of gas sold by the Commission are shown in Figure 4.

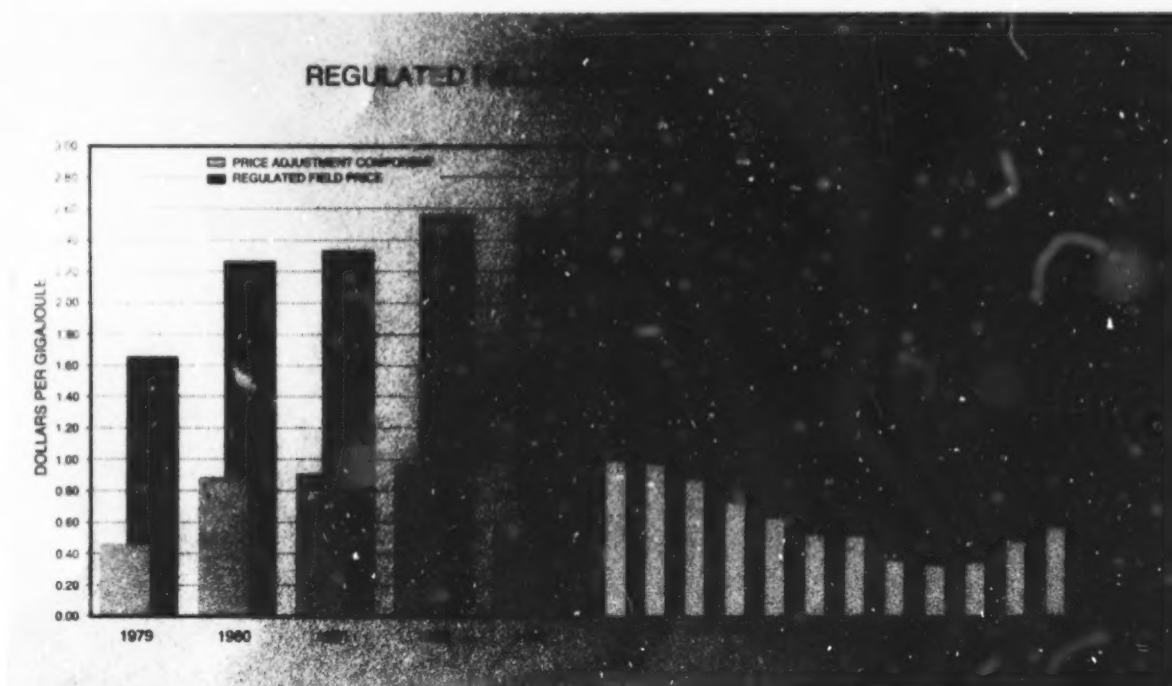
Each month the Commission calculates a price adjustment based on proceeds available in the Fund and estimated quantities of natural gas produced for market. Alberta producers receive a monthly price adjustment for all eligible deliveries either through the regulated field price paid by

an original buyer or, in some circumstances, by claiming directly from the Fund. Original buyers are reimbursed from the Fund for price adjustment paid to producers through the regulated field price.

During the year the Commission purchased 2 320 petajoules of natural gas, for which it paid \$4.5 billion and sold for \$5.9 billion, resulting in proceeds to the Fund of \$1.4 billion. Total natural gas production for market was 2 341 petajoules, on which a price adjustment averaging \$0.60 per gigajoule was paid from Fund proceeds.

The price adjustments expressed in dollars per gigajoule set by the Commission during the year were as follows:

January	0.97	July	0.49
February	0.95	August	0.33
March	0.85	September	0.30
April	0.70	October	0.32
May	0.60	November	0.46
June	0.50	December	0.55



Prices for natural gas exported to the United States since January 1, 1979 are shown in Table 4.

TABLE 4
NATURAL GAS EXPORT PRICES
(\$/gigajoule)

Effective Date	Export Price ⁽¹⁾ (U.S. \$)	Average Selling Price (Can. \$)
Jan. 1, 1979	2.013 18	2.363 82
May 1, 1979	2.143 67	2.506 08
Aug. 11, 1979	2.610 00	3.060 59
Nov. 3, 1979	3.220 00	3.776 95
Feb. 17, 1980	4.170 00	4.845 46
Apr. 1, 1981	4.600 00	5.610 01
Apr. 11, 1983	4.100 00	5.059 86
Jul. 6, 1983 ⁽²⁾	3.170 00	3.909 91

⁽¹⁾Except for a lower price for minor quantities exported at Fort Frances.

⁽²⁾Volume Related Incentive Pricing Plan — only applies to export sales in excess of pre-established minimum sales which continue to be priced at \$4.10.

MARKET DEVELOPMENT INCENTIVE PAYMENTS

In order to encourage expansion of markets for Alberta-produced natural gas in provinces east of Alberta, the Canada-Alberta agreement provides for market development incentive payments to be made by the Commission to the federal government. These payments, which amounted to \$39 million for the 12 months ending January 31, 1984, are to be used to subsidize the expansion of natural gas transmission or distribution facilities and for sales promotion programs.

ALBERTA COST OF SERVICE

Alberta cost of service includes costs and charges relating to the acquisition and movement of natural gas from the point of purchase to the Alberta border. Original buyers that remove natural gas from the Province recover these costs from producers through application to the Commission each month for determination of Alberta cost of service in respect of gas purchased in the month. The monthly averages of Alberta costs of service determined by the Commission over the last five years are shown in Figure 5.

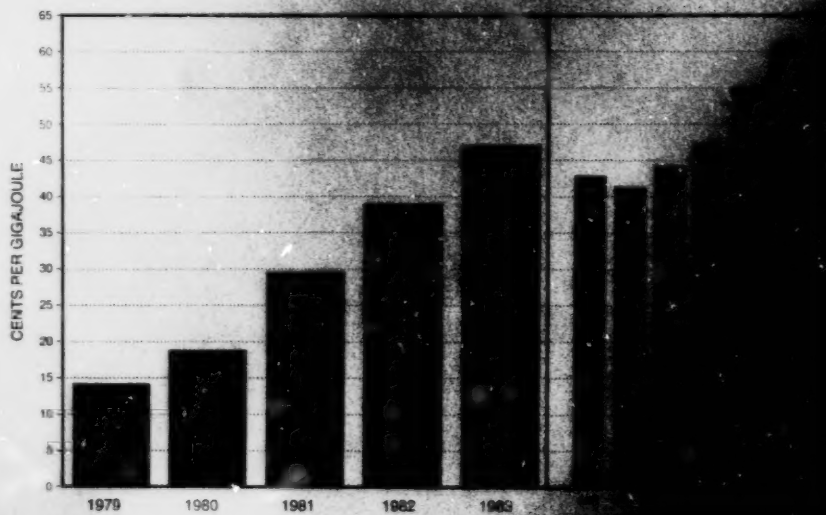
In 1983, transportation represented 51 percent of the total Alberta costs of service while costs of financing take-or-pay payments for gas not taken amounted to 34 percent. Administration costs of the original buyers made up the remaining 15 percent.

The Commission, upon an application by an original buyer or on its own initiative, makes rulings on matters of principle and matters involving categories of costs and charges eligible for inclusion in Alberta cost of service. Any Alberta cost of service determination made by the Commission may be appealed to the Public Utilities Board for public hearing.

FIG. 4
DESTINATION GAS SOLID



AVERAGE OF ALBERTA COSTS OF SERVICE



OTHER ACTIVITIES

REGULATORY ANALYSIS

The Commission filed interventions in several regulatory proceedings before the National Energy Board, monitored a natural gas feedstock inquiry initiated by the Ontario Energy Board and presented a submission on behalf of the Government of Alberta before the United States Department of Energy's Economic Regulatory Administration with respect to its examination of natural gas import policy criteria.

Evidence and argument were presented in an inquiry initiated by the National Energy Board relating to the supply and marketing of heavy fuel oil and its impact on natural gas markets in Eastern Canada. The Commission submitted that Canadian refineries have the technical capability to meet the existing and potential domestic demand for heavy fuel oil, and that continued compensation for imported fuel oil adversely affected natural gas markets. Although advocating the removal of the subsidy, the Commission argued against the need to otherwise impede imports.

An active role was taken in Phase I of a hearing on an application by Dome Petroleum Limited to construct facilities in British Columbia to transport and liquefy natural gas for export to Japan. The remainder of the regulatory proceeding is in abeyance pending agreement on the supply and pricing of natural gas required for the project.

The Commission monitored an inquiry conducted by the Ontario Energy Board into issues affecting Ontario industries utilizing natural gas as a feedstock. Submissions related to direct industry purchase of natural gas from producers and the potential impact on Alberta producers and Ontario distributors were heard. In its decision the Board determined that the direct purchase of natural gas by Ontario industries from producers should be encouraged as in the long-term public interest of Ontario, but that no special incentives be granted to specific industries through discounted utility rates.

The United States Department of Energy's Economic Regulatory Administration conducted a public conference on the criteria which should be applied to natural gas imports. The Commission appeared on behalf of the Government of Alberta and submitted that imports from Canada should recognize market responsive pricing and be arranged through contracts freely negotiated by buyer and seller, subject to regulatory approval. The Commission also stated that existing contracts should be maintained without change and special consideration should be given to gas delivered through the Prebuild Section of the Alaska Natural Gas Transportation System.

By directive released in February, 1984, the Economic Regulatory Administration outlined new policy guidelines in respect of applications for natural gas imports. Under the guidelines, pricing considerations will no longer be the sole basis for authorizing or denying import applications. New and renegotiated contracts must now meet overall tests of contract flexibility and competitiveness in the market served. Existing contracts will not be abrogated on action initiated by the Economic Regulatory Administration, but the parties are encouraged to negotiate changes to conform with the new policy guidelines. It was recognized that the Prebuild Section of the Alaska Natural Gas Transportation System may merit special consideration.

SPECIAL PROJECTS

The Commission initiated a number of studies to identify marketing opportunities and assess competitive pricing for natural gas. These studies included an assessment of the potential for increased Canadian natural gas sales and an evaluation of the capacity of existing pipeline systems to transport additional volumes. In addition, a study was completed which identified competitive energy prices in United States markets served by Canadian gas and the impact of market pricing on Alberta field prices.

An examination was made of the capability of the Canadian refining industry to meet demand for heavy fuel oil in eastern Canada. The structure of the domestic refining industry was examined to support a forecast of supply and demand for crude oil and petroleum products over the next decade. In another study, alternative pricing systems for NORP oil were examined.

The Commission participated in a federal/provincial task force to formulate appropriate incentives to increase natural gas sales in eastern Canada. A domestic natural gas incentive pricing plan was announced in the spring of 1984.

The Commission was involved in a task force which recommended and implemented an incentive price system for natural gas exports. Later in the year, this task force also assessed longer term options for export pricing.

SYNCRUDE PROJECT

At the direction of the Government of Alberta, the Commission markets the Province's share of synthetic oil production from the Syncrude Canada Limited project and, by agreement, the share of one other participant. The province has a 16.74 percent equity participation in the project and a 50 percent share of deemed net profits in lieu of royalty. In 1983 the net profits share was taken as production in kind. The Commission marketed approximately 35 percent of the total 6.5 million cubic metres of synthetic oil produced by the project.

In addition to the Commission's functions, the Chairman of the Commission is the Alberta royalty negotiator with respect to synthetic oil produced by the project. This involves establishment of the value of synthetic oil to be used as a factor in determining net profits. At year end this value was \$243.06 per cubic metre at the plant gate, including compensation of \$53.10 per cubic metre paid by the federal government to reflect international prices.

WORLD SCENE

INTERNATIONAL (excluding communist countries)

Energy consumption, when compared with the previous three years, declined at a more moderate rate of one per cent. Under conditions of excess supply, hydro and nuclear electricity continued to gain market share at the expense of petroleum and natural gas, while coal maintained its share.

Falling demand for crude oil created price uncertainty in world oil markets early in the year. OPEC prices were under pressure from both inside and outside the organization. Nigeria, an OPEC member, cut prices unilaterally as did non-OPEC producers of North Sea crude. A semblance of order was restored in March when OPEC members agreed to lower official prices by \$5.00 (U.S.) per barrel and established controls on production at a ceiling of 17.5 million barrels per day, approximately one million barrels per day below 1982 production levels.

OPEC's share of supply continued to slip, from 41 to 39 percent (Figure 6). Most of the decline was absorbed by Saudi Arabia, acting as a buffer to maintain an orderly market. Saudi Arabia became directly involved in oil trading by stockpiling supplies in reaction to Iranian threats to block the Straits of Hormuz. These actions contributed to stable spot prices over the year. Spot market prices are shown in Figure 7.

There was considerable activity on the newly-formed crude oil commodity futures market in the United States. By year-end, over 417 million barrels of crude oil had been traded on this market.

Proven reserves of conventional crude oil fell marginally to 585 billion barrels as reserve additions did not keep pace with production. However, the reserve life index increased for the fourth consecutive year due to a lower rate of production.

There was ongoing improvement in efficiency of refining operations in response to highly competitive market conditions. Reduced product demand and low margins were instrumental in causing refining capacity to fall by four percent to 58 million barrels per day, with major reductions occurring in Western Europe and the United States.

A number of countries took steps to improve the investment climate to encourage exploration and development. Incentives offered led to record drilling and production levels in the North Sea and exploration was attracted to Third World countries.

Re-evaluation of Japanese energy policy and of United States import arrangements for natural gas were indicative of a growing emphasis on lower-cost energy supplies and de-emphasis of security of supply. This trend was also evident through increased activity on spot markets supplanting volumes earlier moved under longer-term contracts.

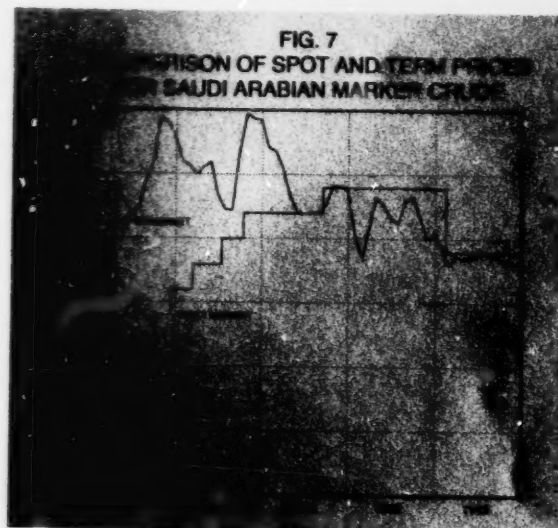
Demand for natural gas fell by two percent, with an increase in Western Europe being more than offset by a six percent decline in the United States. Reserves rose marginally to 1 750 trillion cubic feet. The year marked initial delivery of Algerian natural gas to Italy via the Trans-Mediterranean

pipeline. Deliveries of Soviet natural gas through the Yamal pipeline to Western Europe began in early 1984. A downturn in LNG trade was signaled by the discontinuance of high-cost imports of Algerian LNG to the United States.

UNITED STATES

The downward trend in energy consumption of the previous four years continued in 1983. Consumption fell by 0.5 percent despite growth in real GNP of 3.3 percent, reflecting the continued effect of conservation activity and technological changes in the manufacturing sector. The petroleum and natural gas share of primary energy consumption declined while coal and electricity improved their positions, as illustrated in Table 5.

Petroleum consumption fell by one percent due to weak demand for heavy fuel oil for industrial use and power generation. As the year progressed there were signs that the long-awaited recovery in demand for lighter petroleum products had begun. Demand for gasoline and distillates increased in the second half of the year and imports were up sharply.

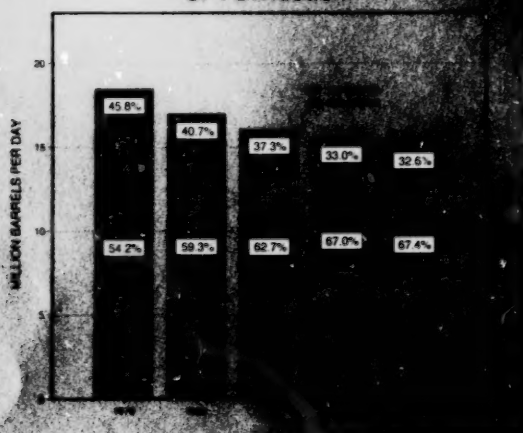


Imports of petroleum declined by two percent to 33 percent of total requirements. Sources of supply continued to shift from Middle East countries and the largest volumes were imported from Mexico. Imports from Canada were at their highest levels since 1976, aided by an increasing supply of Canadian heavy crude and a strong demand for asphalt in the United States due to federal incentive programs encouraging road construction. Sources of petroleum supply since 1979 are shown in Figure 8.

Domestic crude oil production was virtually the same as in 1982, at 8.7 million barrels per day. Additional output from Alaska offset declines in the lower 48 states. Production levels were maintained as a result of the heavy drilling activity in 1981-82. Average wellhead prices for crude oil fell from \$28.52 (U.S.) per barrel to \$26.19 (U.S.) per barrel.

Although exploration activity was at a high level, based on historical standards, well completions declined for the first time since the 1973 Arab oil embargo. Completions were down by six percent from 1982 levels primarily as a result of reduced drilling for natural gas. Proven reserves of crude oil fell from 28 to 27 billion barrels and natural gas reserves dropped from 202 to 198 trillion cubic feet.

FIG. 8
TOTAL UNITED STATES CONSUMPTION
OF PETROLEUM



To improve efficiency, more refineries were closed and refining capacity was reduced five percent to 15.9 million barrels per day. Refinery utilization averaged 73 percent of capacity compared to 70 percent in 1982.

Natural gas consumption fell by six per cent due to fuel switching, warm weather and the continued effects of conservation. Estimates of surplus deliverability, the 'gas bubble', ranged between three and four trillion cubic feet for the year.

TABLE 5
U.S. PRIMARY ENERGY CONSUMPTION
(Quadrillion Btu's)

	Petroleum	Natural Gas (Dry)	Coal	Hydro Elec- tricity	Nuclear Elec- tricity	Other	Total
1979	37.1	20.7	15.1	3.1	2.7	0.2	78.9
1980	34.2	20.4	15.5	3.1	2.7	0.1	76.0
1981	31.9	19.9	16.0	3.1	3.0	0.1	74.0
1982	30.2	18.5	15.3	3.6	3.1	0.1	70.8
1983	30.0	17.4	15.8	3.9	3.2	0.1	70.4

The natural gas industry scrambled to compete in a more competitive energy market. Pipeline companies sought to renegotiate price and purchase obligations with gas producers. Competition was sharpened by spot market sales from pipelines to large industrial customers. By year-end, about six percent of United States production of natural gas was delivered through such arrangements. Competition led to a reduction in natural gas wellhead prices, arresting the upward price spiral of the last ten years. Industrial prices for natural gas stabilized in 1983, as shown in Table 6. Average residential prices, however, continued to increase over the year.

Natural gas production was down ten percent from the prior year. Imports were at 1982 levels, as reduced imports from Canada and Mexico were offset by additional deliveries of Algerian LNG in the first six months of the year.

As a result of the recession and excess domestic supply, high-cost imports of natural gas came under legislative and regulatory review. Guidelines for the importation of gas were released by the Economic Regulatory Administration in early 1984. These guidelines required more flexible pricing and delivery obligations for new imports. Authorizations for new imports of Canadian gas were limited to shorter-term, provisional arrangements and renegotiation of existing contracts was encouraged. High-cost imports of LNG from Algeria were suspended in December.

TABLE 6
COST OF FOSSIL FUEL DELIVERED TO
STEAM ELECTRIC UTILITY PLANTS
IN THE U.S.

(U.S. \$ per million Btu's)

	Coal	Residual Oil	Natural Gas
1979	1.22	3.00	1.75
1980	1.35	4.28	2.21
1981	1.53	5.29	2.83
1982	1.65	4.76	3.38
1983	1.67	4.43	3.39

CANADA

As a result of declining consumption and increased supply, energy surplus to Canadian requirements, increased in 1983. Conservation continued to have an impact, as consumption fell by four percent, despite an increase in real GNP. Petroleum and natural gas shares of the market continued to lose to electricity, while coal maintained its position. Primary energy consumption by source is illustrated in Figure 9.

Production of crude oil was up six percent, electricity generation and coal production each increased three percent, while natural gas fell seven percent.

Reduced markets led to the closure of six refineries during the year. Refining capacity fell 38 thousand cubic metres per day and utilization of remaining capacity increased from 65 to 74 percent.

Crude oil was produced at capacity over the last half of 1983 following federal government approval of exports of light crude. Earlier in the year, shut-in production of crude oil varied from a low of seven thousand to a high of 27 thousand cubic metres per day. Heavy crude oil was produced at capacity throughout the year. As a result of reduced domestic demand and increased exports, Canada was effectively self-sufficient in crude oil for the first time since 1974.

Demand for petroleum products fell almost eight percent from 1982 and has fallen 23 percent since 1980. Declines were experienced for all main products, particularly for heavy fuel oil. The gasoline market saw active price competition during the summer, particularly in eastern Canada, as companies vied to retain market share.

Well completions in Canada were up eight percent as a result of increased drilling in Saskatchewan and frontier regions. In contrast, well completions were down 12 percent in Alberta. As a result of the depressed market for natural gas, drilling activity continued to concentrate on oil prospects. Oil well completions increased 66 percent, while gas completions fell 45 percent. Proven reserves of crude oil, however, declined an estimated four percent.

It was another year of adjustment in energy policy. Programs were implemented to encourage exploration and development of crude oil and to maintain sales of natural gas. Amendments to the Canada-Alberta agreement provided for the reclassification of special old oil to higher-priced new oil and for a redefinition and revised calculation of new oil prices. A volume related incentive price for natural gas exports to the United States was implemented in midyear and negotiations continued towards providing an incentive price to industrial users in eastern Canada.

Sales of natural gas fell five percent from 1982 to 63 billion cubic metres. Sales in Canada declined three percent to 43 billion cubic metres while exports dropped nine percent to 20 billion cubic metres. The major market loss in Canada was in Ontario, offset partially by gains in Quebec resulting from expansion of the Trans Quebec and Maritimes Pipeline Inc. system. Continued conservation

and warm weather contributed to the decline. Natural gas prices rose to levels more representative of commodity value but price discounting and incentives offered by provincial electric utilities resulted in strong price competition.

The export price for natural gas was reduced on April 1, 1983 from \$4.60 (U.S.) to \$4.10 (U.S.) per gigajoule. On July 6, 1983 an incentive price of \$3.17 (U.S.) per gigajoule was introduced applicable to annual volumes exceeding 50 percent of licensed amounts. A later adjustment provided for monthly application of the incentive price. In spite of these measures, less than one-half of authorized export volumes were delivered in 1983. Several contracts between Canadian exporters and United States importers were re-negotiated to reduce purchase obligations and modify take-or-pay requirements.

The level and uniformity of the export price were cited by United States authorities as primary

obstacles to imports of Canadian natural gas. The Economic Regulatory Administration guidelines of February, 1984 limit additional Canadian export sales until Canadian contract arrangements more effectively meet competitive conditions in the markets to be served.

Deliveries of natural gas from the Venture discovery off Sable Island are scheduled to begin in mid-1988. Development, however, is dependent on price competitiveness in the northeast United States market. Progress toward exports of LNG to Japan was further delayed pending resolution of supply pricing and economic issues.

Domestic consumption of electricity increased by two percent to 352 billion kilowatt hours and exports increased by 14 percent to 39 billion kilowatt hours. Canada's position as a net exporter of coal was enhanced as exports increased to 17 million tonnes while imports fell to 14 million tonnes.





ALBERTA LEGISLATURE

OFFICE OF THE AUDITOR GENERAL

AUDITOR'S REPORT

To the Members of the
Alberta Petroleum Marketing Commission

I have examined the balance sheet of the Alberta Petroleum Marketing Commission as at December 31, 1983 and the statements of revenue and expenditure for the Operating Fund and the Petroleum Marketing Fund for the year then ended. My examination was made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as I considered necessary in the circumstances.

In my opinion, these financial statements present fairly the financial position of the Commission as at December 31, 1983 and the results of its operations for the year then ended in accordance with the disclosed basis of accounting, considered appropriate in the circumstances, as described in Note 2 to the financial statements applied, after giving retroactive effect to the change in the method of accounting for the gain on sale of inventory as described in Note 3 to the financial statements, on a basis consistent with that of the preceding year.

A handwritten signature in black ink, appearing to read "D. W. R. G.", followed by a horizontal line.

C.A.
Auditor General

Edmonton, Alberta
April 11, 1984

Alberta PETROLEUM MARKETING COMMISSION

BALANCE SHEET

As At December 31

ASSETS

	<u>1983</u>	<u>1982</u>
OPERATING FUND		
Current Assets		
Cash and short-term investments	\$ 4,195,897	\$ 3,182,429
Accounts receivable	<u>118,225</u>	<u>422,186</u>
	4,314,122	3,604,615
 Furniture, equipment and leasehold improvements, at cost (Note 4)	 <u>2,257,548</u>	 <u>1,719,602</u>
	<u>6,571,670</u>	<u>5,324,217</u>
 PETROLEUM MARKETING FUND		
Current Assets		
Cash and short-term investments	19,626,549	14,617,560
Accounts receivable (Note 6)	979,705,877	780,832,040
Inventory, at cost	<u>35,084,009</u>	<u>26,207,644</u>
	1,034,416,435	821,657,244
	<u>\$1,040,988,105</u>	<u>\$826,981,461</u>

The accompanying notes are part
of these financial statements.

LIABILITIES

	<u>1983</u>	<u>1982</u>
OPERATING FUND		
Current Liabilities		
Accounts payable	\$ 645,186	\$ 181,895
Deferred contributions	<u>3,668,936</u>	<u>3,422,720</u>
	<u>4,314,122</u>	<u>3,604,615</u>
 Capital surplus	 <u>2,257,548</u>	 <u>1,719,602</u>
	<u>6,571,670</u>	<u>5,324,217</u>
 PETROLEUM MARKETING FUND		
Current Liabilities		
Accounts payable to Crown lessees	609,908,925	485,215,417
Crown royalty payable	300,977,982	257,764,597
Buy/sell, freehold and transportation payable	<u>123,529,528</u>	<u>78,677,230</u>
	<u>1,034,416,435</u>	<u>821,657,244</u>
	<u>\$1,040,988,105</u>	<u>\$826,981,461</u>

Alberta PETROLEUM MARKETING COMMISSION

**STATEMENT OF REVENUE AND EXPENDITURE
OPERATING FUND**

For The Years Ended December 31

	<u>1983</u>	<u>1982</u>
Revenue		
Contributions from (to) the Province	\$ 539,627	\$ (689,530)
Interest (Note 5)	2,087,559	2,127,388
Gain on sale of inventory	3,839,701	4,126,003
Income from export marketing	216,333	—
	<u>6,683,220</u>	<u>5,563,861</u>
Expenditure		
Salaries and employee benefits	3,744,293	3,185,461
Rental of premises (Note 9)	1,112,279	339,622
Furniture and equipment	539,501	401,710
Technical studies	435,208	493,731
Travel	254,642	193,719
Computer services	136,471	282,989
Printing and office supplies	125,615	107,387
Personnel consultants	83,098	99,026
Rental of office equipment	65,565	50,192
Publications and periodicals	52,344	52,842
Postage and freight	32,944	16,372
Telephone	27,615	23,649
Leasehold improvements	20,194	220,386
Advertising	5,939	52,538
Insurance	5,426	421
Building and equipment maintenance	1,231	30,523
Miscellaneous	10,855	13,293
	<u>6,683,220</u>	<u>5,563,861</u>
Excess of revenue over expenditure	\$ —	\$ —

Alberta PETROLEUM MARKETING COMMISSION
STATEMENT OF REVENUE AND EXPENDITURE
PETROLEUM MARKETING FUND
For The Years Ended December 31

	<u>1983</u>	<u>1982</u>
Revenue (Note 7)		
Sale of petroleum, pentanes plus and bitumen	\$ 9,983,676,452	\$7,811,707,747
New oil reference price supplement	756,556,216	239,023,829
Special old oil price supplement	23,108,604	113,529,857
	<u>10,763,341,272</u>	<u>8,164,261,433</u>
Expenditure		
Purchases	1,161,768,548	567,601,166
Transportation	142,700,220	115,624,758
	<u>1,304,468,768</u>	<u>683,225,924</u>
Crown lessees' share	6,457,893,924	4,888,577,292
Crown royalty share	3,000,978,580	2,592,458,217
	<u>10,763,341,272</u>	<u>8,164,261,433</u>
Excess of revenue over expenditure	\$ —	\$ —

NOTES TO THE FINANCIAL STATEMENTS

December 31, 1983

Note 1 Authority

The Alberta Petroleum Marketing Commission operates under the authority of the Petroleum Marketing Act, Chapter P-5, Revised Statutes of Alberta 1980.

Note 2 Significant Accounting Policies

General

These financial statements have been prepared in accordance with generally accepted accounting principles except that no depreciation or amortization has been provided on fixed assets as purchases are charged to operating fund expenditure in the year of acquisition. Furniture, equipment and leasehold improvements are shown on the balance sheet at original cost with the offsetting credit to capital surplus.

Deferred Contributions

The unexpended portion of contributions received from the Province of Alberta has been deferred to cover operating costs for the period to March 31, 1984. Contributions by the Province are based on a yearly budget for the period April 1 to March 31.

Operating Fund Expenditure

The Natural Gas Pricing Agreement Act Fund is administered by the Alberta Petroleum Marketing Commission pursuant to the Natural Gas Pricing Agreement Act. The expenditure related to the administration of this Fund is reflected in the Statement of Revenue and Expenditure - Operating Fund.

Inventory

The inventory represents the Crown royalty share of petroleum and pentanes plus remaining in the feeder pipelines at December 31. Gains and losses as a result of price changes are included as revenue of the Operating Fund.

Changes in Financial Position

A statement of changes in financial position is not provided as disclosure in these financial statements is considered to be adequate.

Note 3 Change in Accounting Policies

Gain on Sale of Inventory

In previous years the Commission did not record in the financial statements the gain on sale of inventory resulting from price increases under the Canada-Alberta agreement on energy pricing, dated September 1, 1981. During the year the Commission changed its method of accounting for this gain and now recognizes such realized gains as revenue of the Operating Fund. As a result of this change, which has been retroactively applied, 1982 contributions by the Province have been reduced by \$4,126,003.

Note 4 Furniture, Equipment and Leasehold Improvements

Changes in furniture, equipment, and leasehold improvements were as follows:

	<u>Balance</u> <u>December 31, 1982</u>	<u>Purchases</u>	<u>Disposals</u>	<u>Balance</u> <u>December 31, 1983</u>
Furniture and equipment	\$1,139,144	\$539,501	\$(21,749)	\$1,656,896
Leasehold improvements	<u>580,458</u>	<u>20,194</u>	<u>—</u>	<u>600,652</u>
	<u>\$1,719,602</u>	<u>\$559,695</u>	<u>\$(21,749)</u>	<u>\$2,257,548</u>

Note 5 Interest

Interest represents amounts earned from account balances and short-term investments in the Petroleum Marketing Fund and the Operating Fund.

Note 6 Petroleum Marketing Fund Accounts Receivable

Petroleum Marketing Fund accounts receivable consist of the following:

	<u>1983</u>	<u>1982</u>
Transactions related to December petroleum deliveries	\$973,912.937	\$772,927,612
Prior months' accounts, net	5,792,940	7,904,428
	<u>\$979,705.877</u>	<u>\$780,832,040</u>

Note 7 Revenue — Petroleum Marketing Fund**New Oil Reference Price Supplement Payments**

Effective January 1, 1982, pursuant to the Canada-Alberta agreement on energy pricing dated September 1, 1981, oil discovered after December 31, 1980 became eligible for the New Oil Reference Price (NORP). NORP supplement payments were received from the federal government for the difference between the established NORP price and the field price for conventional old oil. The NORP supplement payments were extended to cover pentanes plus and bitumen effective April 1, 1982.

Special Old Oil Price Supplement Payments

Effective July 1, 1982, pursuant to The National Energy Program Update of May 1982, oil discovered from April 1, 1974 to December 31, 1980 became eligible for the Special Old Oil Price (SOOP). Pentanes plus discovered from January 1, 1974 to December 31, 1980 also became eligible for the SOOP price on July 1, 1982. SOOP supplement payments were received from the federal government for the difference between the established SOOP price and the field price for conventional old oil. This category became eligible for NORP prices, effective July 1, 1983.

Note 8 Syncrude Project

The Commission, through agency agreements with the Province of Alberta and PanCanadian Petroleum Limited, markets their shares of synthetic oil from the Syncrude Project. The Commission, acting by appointment from the Minister of Energy and Natural Resources, also markets the Crown royalty share of synthetic oil.

The marketing activities undertaken by the Commission relative to these transactions are not reflected in these financial statements.

Note 9 Lease Commitment

Effective December 1, 1981, the Commission signed a fifteen year lease for office accommodation at a minimum annual rental of \$692,360.

The 1982 expenditure for 'Rental of premises' was reduced by an amount of \$549,727. This amount was paid to the Commission by the landlord pursuant to an agreement which compensated for the difference between the rental rate on the square footage at its former location and the rate at the new location, for the period to the expiry of the old lease in June 1984.

Note 10 Comparative Figures

The 1982 figures have been restated where necessary to conform to the 1983 presentation.

Note 11 Approval of Financial Statements

These financial statements were approved by management on April 11, 1984.



ALBERTA LEGISLATURE

OFFICE OF THE AUDITOR GENERAL

AUDITOR'S REPORT

To the Members of the
Alberta Petroleum Marketing Commission

I have examined the balance sheet of the Natural Gas Pricing Agreement Act Fund as at December 31, 1983 and the statement of revenue and expenditure for the year then ended. My examination was made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as I considered necessary in the circumstances.

In my opinion, these financial statements present fairly the financial position of the Fund as at December 31, 1983 and the results of its operations for the year then ended in accordance with generally accepted accounting principles applied on a basis consistent with that of the preceding year.

A handwritten signature in dark ink, appearing to read "D. W. Royce", with a horizontal line underneath.

C.A.
Auditor General

Edmonton, Alberta
April 11, 1984

NATURAL GAS PRICING AGREEMENT ACT FUND

BALANCE SHEET

As At December 31

ASSETS

	<u>1983</u>	<u>1982</u>
Current Assets		
Cash and short-term investments	\$ 20,340,220	\$ 13,203,335
Accounts receivable (Note 3)	<u>159,663,183</u>	<u>255,542,145</u>
	<u>\$180,003,403</u>	<u>\$268,745,480</u>

LIABILITIES

Current Liabilities		
Price adjustments payable	\$156,053,161	\$268,745,480
Market development incentive payable (Note 4)	<u>23,950,242</u>	<u>—</u>
	<u>\$180,003,403</u>	<u>\$268,745,480</u>

The accompanying notes are part
of these financial statements.

NATURAL GAS PRICING AGREEMENT ACT FUND
STATEMENT OF REVENUE AND EXPENDITURE
For The Years Ended December 31

	<u>1983</u>	<u>1982</u>
Revenue		
Natural gas sales	\$5,981,221,356	\$6,330,714,339
Interest	1,457,629	2,778,697
	<u>5,982,678,985</u>	<u>6,333,493,036</u>
Expenditure		
Natural gas purchases	4,549,612,739	3,906,419,781
Price adjustments	1,406,003,534	2,402,343,405
Market development incentive (Note 4)	27,062,713	24,729,850
	<u>5,982,678,985</u>	<u>6,333,493,036</u>
Excess of revenue over expenditure	<u>\$ —</u>	<u>\$ —</u>

NATURAL GAS PRICING AGREEMENT ACT FUND

NOTES TO THE FINANCIAL STATEMENTS

December 31, 1983

Note 1 Authority

The Natural Gas Pricing Agreement Act Fund is established by the Natural Gas Pricing Agreement Act, Chapter N-4, Revised Statutes of Alberta 1980, as amended.

Note 2 Significant Accounting Policies

Administration Costs

In accordance with the Natural Gas Pricing Agreement Act, the Fund is administered by the Alberta Petroleum Marketing Commission. Costs of administration are reflected in the Commission's Statement of Revenue and Expenditure - Operating Fund.

Changes in Financial Position

A statement of changes in financial position is not provided as disclosure in these financial statements is considered to be adequate.

Note 3 Accounts Receivable

Accounts receivable consist primarily of net proceeds from December natural gas sales.

Note 4 Market Development Incentive Payments

Pursuant to the Canada-Alberta agreement on gas pricing of November 1981, payments out of the Fund are required to be made by the Commission to the Government of Canada for the purpose of facilitating the expansion of markets in provinces east of Alberta for gas produced in Alberta.

Note 5 Approval of Financial Statements

These financial statements were approved by management on April 11, 1984.

COMMISSION DIRECTORY

COMMISSION MEMBERS*

D. Wayne Minion
Chairman

R. Douglas Hall
Vice Chairman

David L. Willis
Vice Chairman

SECRETARY AND SOLICITOR

Donald C. Hetland

AUDITOR

Edwin K. Adams

ADMINISTRATION

Dugald MacLachlan
Administrative Assistant

Betty A. Lilly
Manager, Office Services

FINANCE

Garth K. Palmer
General Manager

T. N. Ritchie Fons
Manager, Accounting

PETROLEUM

James E. MacKenzie
General Manager

Robert J. McLean
Manager, Petroleum Marketing

Donald M. Olineck
Manager, Petroleum Supply

Ronald J. Smith
Manager, Petroleum Operations

NATURAL GAS

Vernon M. Thomas
General Manager

H. Daniel Maerz
Manager, Regulatory Analysis

William A. McKain
Manager, Cost of Service

Adrian Smith
Manager, Natural Gas Sales & Claims

INFORMATION SERVICES

Richard W. Tovell
General Manager

Sam K. Leung
Manager, Computer Services

Susan J. Myra
Manager, Systems Development

ENGINEERING & PLANNING

Raymond S. Dunwald
General Manager

Gary E. Baerg
Manager, Technical Services

Glen E. Ferguson
Manager, Market Analysis & Planning — Natural Gas

Robert F. McDonald
Manager, Market Analysis & Planning — Petroleum

At December 31, 1983 the staff of the Commission numbered 104.

*Russell H. Purdy, F.C.A., retired as of August 15, 1983, after serving as a Member of the Commission since its inception to December 31, 1979 and as Vice Chairman from January 1, 1980.

POOR

QUALITY

ORIGINAL